Investor Presentation

March 2023

Forward Looking Statement

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that Unit Corporation (the Company) expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "believe," "expect," "anticipate," "plan," "intend," "foresee," "should," "would," "could," or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including as to the Company's drilling program, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's expectations and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas, availability of drilling equipment and personnel, availability of sufficient capital to execute the Company's business plan, the Company's ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected and other risks disclosed under "Risk Factors" in the Company's most recent Form 10-K and Form 10-Q's filed thereafter. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law. This presentation may contain certain terms, such as locations and estimated ultimate recovery ("EUR") and other similar terms that describe estimates of potential wells and potentially recoverable hydrocarbons that SEC rules prohibit from being included in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and may not constitute "reserves" within the meaning of SEC rules and accordingly, are subject to substantially greater risk of being actually realized. These estimates are based on the Company's existing models and internal estimates. Actual quantities that may be ultimately recovered from the Company's interests will differ substantially. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of unproved reserves may change significantly as development of the Company's core assets provide additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

This presentation may contain financial measures that have not been prepared in accordance with U.S. Generally Accepted Accounting Principles ("non-GAAP financial measures") including PV-10 reserve values and certain operating measures such as Adjusted EBITDA. The non-GAAP financial measures should not be considered a substitute for financial measures prepared in accordance with U.S. Generally Accepted Accounting Principles ("GAAP"). We urge you to review the reconciliations of the non-GAAP financial measures to GAAP financial measures in the appendices.

Investment Highlights

- Reserves as of December 31, 2022[1]:
  - $785 million based on the SEC standardized measure
  - PDP PV-10:
    - $957 million based on SEC pricing
    - $585 million based on forward strip pricing
- All 14 BOSS rigs are contracted and operating
- Strong balance sheet as of December 31, 2022:
  - $214 million of cash & cash equivalents
    - See note below regarding payment of January 2023 special dividend
  - No long-term debt, $35 million bank facility
- Free cash flows supportive of both future shareholder returns and potential development opportunities
- Substantial tax shield: $331 million of NOL's as of December 31, 2022
- Dividend policy
  - Special dividend of $10 per share paid in January 2023, totaling $96 million
  - Quarterly variable dividend going forward, $2.50 per share in Q2 2023
- Unit's ownership interest in Superior Pipeline Company, LLC (Superior) to be sold for $20 million

[1] See appendix for reconciliation of reserve values to standardized measure

2022 Consolidated Financial Highlights

		1Q22 [1]		2Q22		3Q22		4Q22		FY2022
					(in thousands, except per share amounts)					
Revenues:										
Oil and natural gas	$	76,810	$	100,912	$	80,026	$	57,734	$	315,482
Contract drilling	$	28,882	$	33,642	$	40,256	$	44,590	$	147,370
Gas gathering and processing	$	82,673	$	-	$	-	$	-	$	82,673
Total revenues	$	188,365	$	134,554	$	120,282	$	102,324	$	545,525
Net income attributable to Unit Corporation	$	(46,877)	$	80,093	$	55,818	$	59,335	$	148,369
Basic earnings per share	$	(4.66)	$	7.99	$	5.70	$	6.16	$	15.03
Diluted earnings per share	$	(4.66)	$	7.82	$	5.60	$	6.07	$	14.78
Adjusted EBITDA [2]	$	50,823	$	44,370	$	43,270	$	36,611	$	175,074
Capital expenditures	$	8,568	$	5,979	$	8,998	$	10,051	$	33,596

[1] Reflects Superior activity on a consolidated basis during the two months prior to its March 1, 2022 deconsolidation

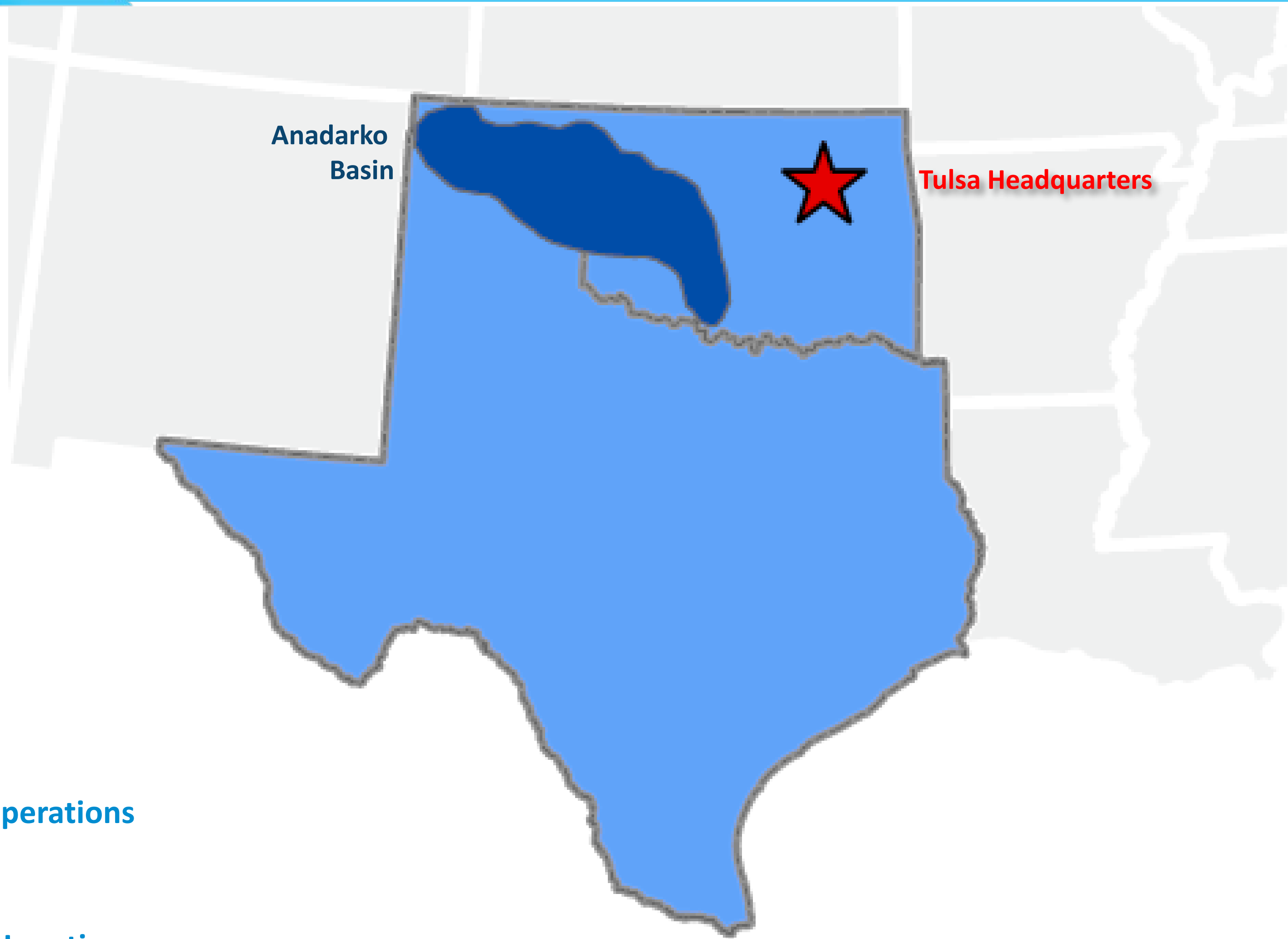
[2] See Appendix 1 for a description of Adjusted EBITDA and reconciliation to net income attributable to Unit Corporation

- Cash and cash equivalents of $214 million as of December 31, 2022
- No outstanding borrowings on $35 million revolver
- Expected federal net operating loss carryforward of $331 million as of December 31, 2022
- See Form 10-K filed with the SEC on March 17, 2023, for more detailed information

Unit Petroleum Company (UPC) Summary

- Efficient, low-cost production and modest decline in PDP reserves
- Substantial developed acreage position of ~202,000 net acres in the Anadarko Basin
- Development strategies:
  - Converting non-producing reserves to producing reserves
  - Evaluating acquisitions of producing properties in core areas
  - High-grading producing properties by selling interests in non-core areas
- Reducing G&A run rate to reflect current smaller footprint and plans

Unit Production Company Operations Footprint



E&P Operations

Office Location

Unit Production Company
2022 Operating and Financial Highlights

	1Q22	2Q22	3Q22	4Q22	YTD
	(In thousands unless otherwise specified)				
Oil and Natural Gas:					
Revenue, before inter-segment eliminations [1]	$ 87,582	$ 100,896	$ 80,026	$ 57,734	$ 326,238
Operating costs, before inter-segment eliminations [1]	$ 24,000	$ 27,603	$ 21,235	$ 21,021	$ 93,859
Average oil price ($/Bbl)	$ 59.72	$ 56.28	$ 56.75	$ 56.31	$ 57.48
Average oil price excluding derivatives ($/Bbl)	$ 92.22	$ 110.29	$ 91.81	$ 82.48	$ 94.28
Average NGLs price ($/Boe)	$ 32.91	$ 34.72	$ 29.39	$ 18.07	$ 30.00
Average NGLs price excluding derivatives ($/Boe)	$ 32.91	$ 34.72	$ 29.39	$ 18.07	$ 30.00
Average natural gas price ($/Mcf)	$ 3.31	$ 4.24	$ 3.57	$ 3.42	$ 3.65
Average natural gas price excluding derivatives ($/Mcf)	$ 4.54	$ 6.62	$ 7.04	$ 4.98	$ 5.79
Oil production (MBbls)	406	309	276	290	1,281
NGL production (MBbls)	613	620	547	368	2,148
Natural gas production (MMcf)	6,514	6,821	5,452	5,424	24,211
Capital expenditures, before inter-segment eliminations [2]	$ 6,390	$ 2,710	$ 6,101	$ 5,836	$ 21,037

[1] Inter-segment eliminations related to activity with Superior during the two months prior to its March 1, 2022 deconsolidation

[2] Inter-segment eliminations related to activity with our Contract Drilling segment during 2022

Unit Production Company Reserves Update

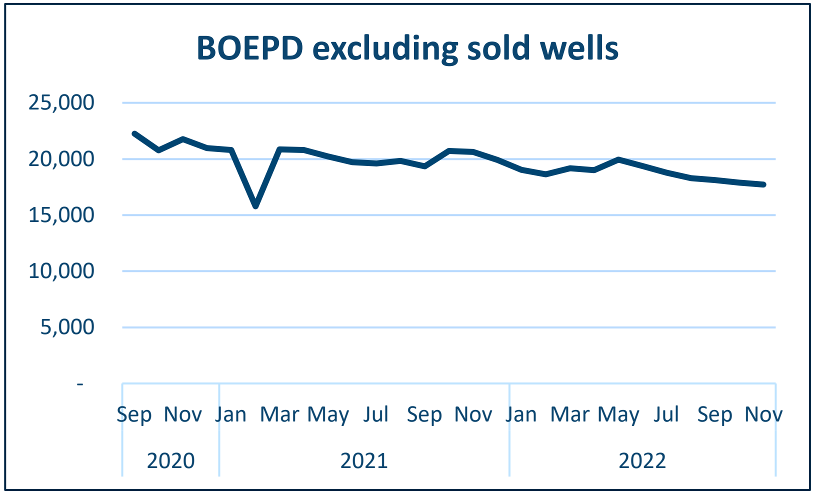
The following table presents the components of the standardized measure of discounted future net cash flows:

	2022 (In thousands)
Future cash inflows	$ 2,918,116
Future production costs	$ (1,142,754)
Future development costs	$ (1,724)
Future income tax expenses	$ (355,350)
Future net cash flows	$ 1,418,288
10% annual discount for estimated timing of cash flows	$ (633,263)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs, and natural gas reserves	$ 785,025

- As of December 31, 2022:
  - SEC pricing PDP PV-10 value of $957 million[1]
    - $93.67/bbl oil and $6.36/mcf gas based on first-of-month prices
    - 7,681 MBO; 212 BCF; 20,132 MBNGL net reserve volume
    - Future revenue attributed 25% to oil, 27% to NGL and 48% to gas
  - Strip pricing PDP PV10 value of $585 million[1]
    - $75.48/bbl oil and $4.69/mcf gas based on strip pricing as of 1/3/2023
    - 7,125 MBO; 195 BCF; 18,802 MBNGL net reserve volume using strip pricing
    - Future revenue attributed 26% to oil, 29% to NGL and 45% to gas

[1] See Appendix 2 for a reconciliation to the standardized measure

Unit Production Company Producing Properties



- ~202,000 net developed acres in Anadarko Basin
- Modest production decline rate
- 4,248 wells (1,347 net wells)
- Low water production
- Optimize production and operating costs
- Perform workovers, recompletions or return-to-production to increase production
    - Anticipated workover and maintenance spend of $3 million per year
- Reduce plugging and abandoning liability
    - Current salvaged equipment pricing creates an opportunity for more economic plugging and abandoning of wells
    - Anticipate plugging and abandoning spend of $2 million per year
- Continued focus on environmental and safety

Unit Production Company Development Potential

- Potential locations in Red Fork, Marchand, Medrano, Meramec, Woodford and Granite Wash
  - Drill or farm-out high-graded drilling locations
  - Monetize non-core drilling locations
- Anticipate drilling or participating in 1 to 2 net wells per year, with development capital expenditures of approximately $10 to $20 million per year consistent with recent historical practice and dependent upon future market conditions
- Participated in 1.34 net wells during 2022

Unit Production Company Divestiture Update

- Sold interests in 727 wells for $57 million during 2022
  - Sold wells in Gulf Coast area, Oklahoma Panhandle, and other non-core assets

- Will continue to sell minor interests in outlying areas and concentrate remaining properties in core fields and plays

Unit Production Company Commodity Hedging

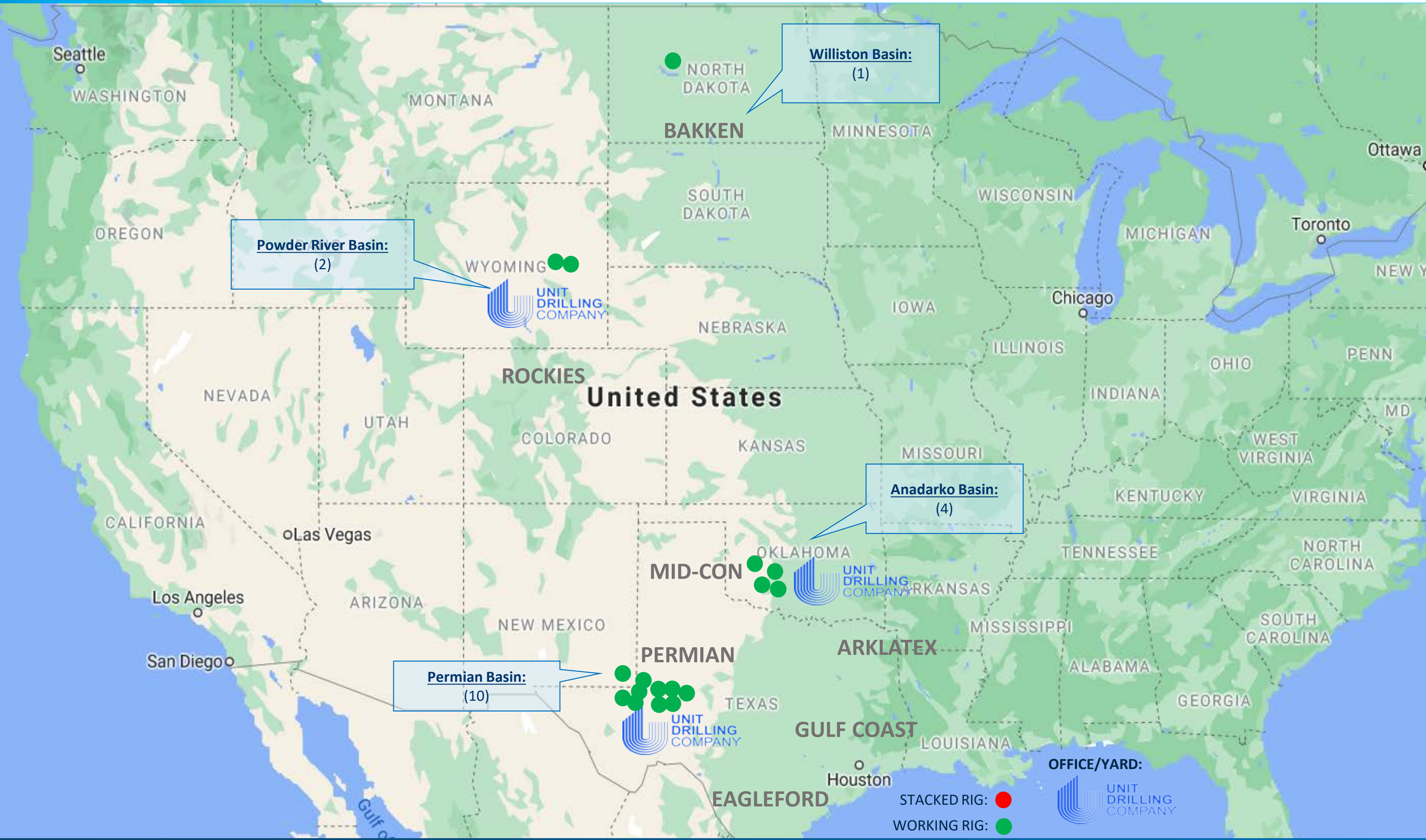
- Net commodity derivative liability of $24 million as of December 31, 2022
- Emergence hedges terminate at the end of 2023

Term	Commodity (instrument)	Contracted Volume	Weighted Average Fixed Price	Contracted Market
Jan’23 - Feb’23	Natural gas (swap)	27,627 MMBtu/day	$9.14	IF – NYMEX (HH)
Jan’23 - Dec’23	Natural gas (swap)	22,000 MMBtu/day	$2.46	IF – NYMEX (HH)
Jan’23 – Mar’23	Natural gas (basis swap)	25,000 MMBtu/day	$(0.17)	NGPL TEXOK
Jan’23 - Feb’23	Crude oil (swap)	1,339 Bbl/day	$95.40	WTI - NYMEX
Jan’23 - Dec’23	Crude oil (swap)	1,300 Bbl/day	$43.60	WTI - NYMEX

Unit Drilling Company (UDC) Summary

- All 14 BOSS rigs contracted in high demand areas
- Average Q4 2022 day rate for BOSS rigs of $28,385
- BOSS rigs are expected to re-contract over next 6 to 12 months
- On-going sales of excess equipment, with $13 million in proceeds received during 2022

Unit Drilling Company Operations Footprint



Unit Drilling Company
BOSS Drilling Rig

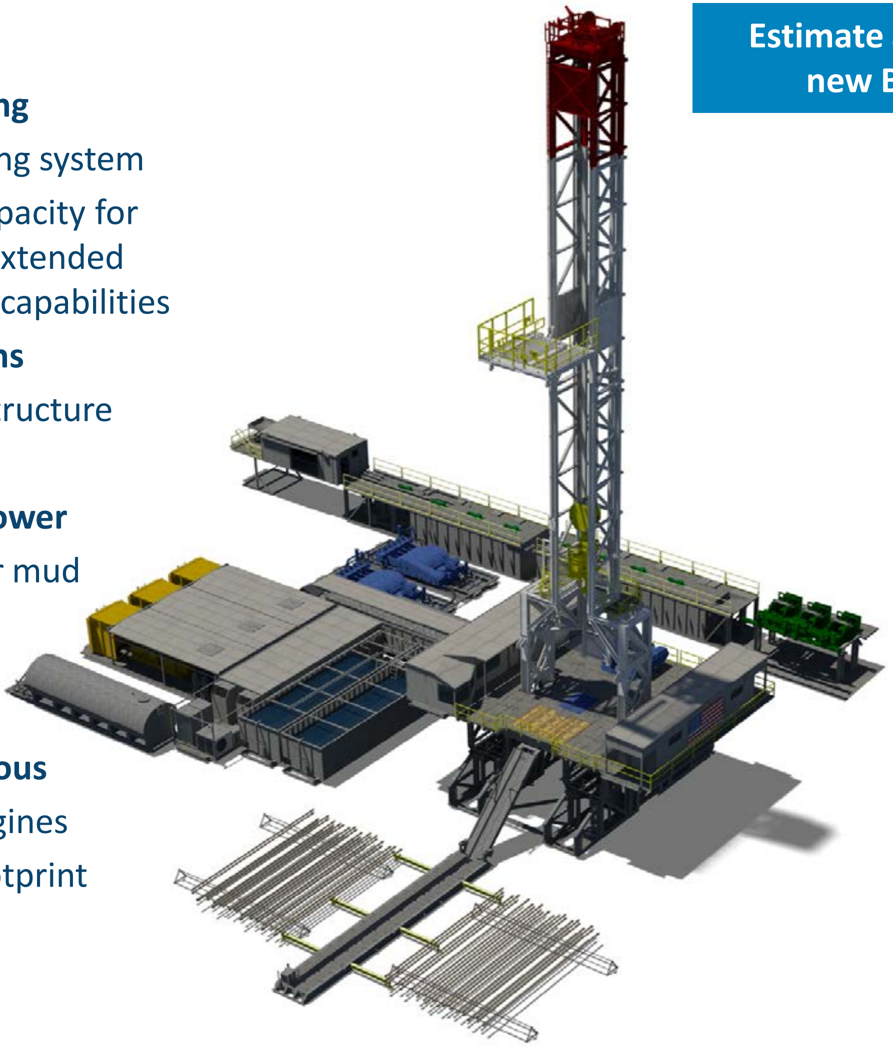
Estimate approx. $35 million to build a new BOSS rig in today's market

Optimized for Pad Drilling
- Multi-direction walking system
- Racking & setback capacity for additional tubulars, extended lateral length drilling capabilities

Faster Between Locations
- Quick assembly substructure
- 32-34 truck loads

More Hydraulic Horsepower
- (2) 2,200 horsepower mud pumps
- 1,500 gpm available with one pump

Environmentally Conscious
- Dual-fuel capable engines
- Compact location footprint



14 BOSS drilling rigs

Unit Drilling Company
2022 Operating and Financial Highlights

		1Q22		2Q22		3Q22		4Q22		YTD
	(In thousands except rig and day amounts, and as otherwise specified)									
Contract Drilling:										
Revenue, before inter-segment eliminations [1]	$	28,882	$	33,642	$	40,256	$	44,960	$	147,740
Operating costs, before inter-segment eliminations [1]	$	26,237	$	25,763	$	25,823	$	27,785	$	105,608
Total drilling rigs available for use at the end of the period		21		21		21		18		18
Average number of drilling rigs in use		15.5		16.3		17.0		17.0		16.4
Total revenue days		1,391		1,483		1,567		1,560		6,001
Average dayrate on daywork contracts ($/day)	$	19,756	$	21,285	$	23,371	$	27,579	$	23,132
Average dayrate on daywork contracts - BOSS Rigs ($/day)	$	20,661	$	21,955	$	24,258	$	28,385	$	23,963
Average dayrate on daywork contracts - SCR Rigs ($/day)	$	16,012	$	18,217	$	19,370	$	23,861	$	19,422
Capital expenditures	$	1,006	$	3,225	$	2,545	$	4,358	$	11,134

[1] Inter-segment eliminations related to activity with our oil and natural gas segment

Environmental & Safety

- Committed to a culture of safe and environmentally friendly operations
- UPC actively reducing methane emissions
- UPC also using recycled produced water for stimulation work thereby reducing use of fresh water
- Strong UDC health & safety track record

Superior Pipeline Company, LLC

- Recently announced future sale of Unit's ownership interest in Superior to joint-venture partners
  - $20 million total proceeds
    - $12 million to be paid at closing
    - $8 million to be paid at the earlier of 12 months from closing or the satisfaction of certain ongoing covenant obligations and other customary conditions
  - Continued shared services support for up to 12 months

- $53 million total cash generated from Superior investment since emergence in September 2020:
  - $33 million in total distributions received by Unit during 2021 and 2022
  - $20 million total sales proceeds to be received by Unit

Returning Value to Shareholders

- Special dividend of $10 per share paid in January 2023
- Quarterly variable dividend policy going forward:
  - $2.50 per share announced for Q2 2023
  - Subsequent variable dividends to be determined based on future operating cash flows, available cash, working capital, and capital expenditure requirements or opportunities, among other factors
- Share repurchase activity from September 2020 emergence to December 31, 2022:

	Shares	Cost	Avg Cost/Share
	(In thousands)		
Repurchase Program	1,794	$68,851	$38.37
From Lenders	600	$9,000	$15.00
Others	78	$1,487	$19.07
Total as of Dec 31, 2022	2,472	$79,338	$32.09

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Appendix 1

Reconciliation of Net Income to Adjusted EBITDA

	1Q22	2Q22	3Q22	4Q22	FY2022
			(in thousands)		
Net income attributable to Unit Corporation	$ (46,877)	$ 80,093	$ 55,818	$ 59,335	$ 148,369
Add: (Gain)/loss on derivatives	$ 64,076	$ (2,609)	$ 12,381	$ (10,238)	$ 63,610
Less: Cash payments on derivatives settled	$ (21,239)	$ (32,884)	$ (28,641)	$ (16,011)	$ (98,775)
Add: (Gain)/loss on change in fair value of warrants	$ 36,612	$ (7,289)	$ -	$ -	$ 29,323
Add: Non-Superior depreciation, depletion, and amortization	$ 5,656	$ 5,661	$ 3,521	$ 3,691	$ 18,529
Add: Loss on deconsolidation of Superior	$ 13,141	$ -	$ -	$ -	$ 13,141
Less: Gain on disposition of assets	$ (2,175)	$ (2,066)	$ (2,158)	$ (1,968)	$ (8,367)
Add: Stock-based compensation expense	$ 1,038	$ 2,847	$ 1,872	$ 961	$ 6,718
Add: ARO accretion expense	$ 493	$ 481	$ 392	$ 432	$ 1,798
Add: Non-Superior interest expense	$ 95	$ 97	$ 37	$ 39	$ 268
Add: Income tax expense	$ -	$ -	$ -	$ 333	$ 333
Add: Reorganization expense	$ 3	$ 39	$ 48	$ 37	$ 127
Adjusted EBITDA	$ 50,823	$ 44,370	$ 43,270	$ 36,611	$ 175,074

Unit believes Adjusted EBITDA provides information useful in assessing operating and financial performance across periods. Unit computes Adjusted EBITDA as net income attributable to Unit Corporation before non-cash valuation changes for commodity derivatives; non-cash valuation changes for the fair value of warrants; non-Superior related depreciation, depletion and amortization; non-cash deconsolidation charges; interest expense; income tax expense; reorganization expense; asset impairments, if any; asset disposition gains and losses; non-cash share-based compensation; accretion on asset retirement obligations; and other items not related to normal operations. Adjusted EBITDA as defined by Unit may not be comparable to similarly titled measures used by other companies.

Appendix 2

Description	Amount
Standardized Measure [1]	$785 million
Discounted effect of future income tax expenses	$172 million
Pre-tax PV-10 value under SEC pricing [2]	$957 million
Impact of adjusting SEC pricing to forward strip pricing	($372) million
Pre-tax PV-10 value under forward strip pricing [3]	$585 million

[1]The standardized measure of discounted future net cash flows relating to proved oil, NGLs, and natural gas reserves (Standardized Measure) is calculated in accordance with US GAAP as the after-tax estimated future cash flows from proved reserves discounted at an annual rate of 10 percent. The benchmark price used for all future reserves was $93.67 per barrel of oil, $39.34 per barrel of NGLs, and $6.36 per Mcf of natural gas, then adjusted for price differentials, based on the 12-month historical average of the beginning-of-month prices in accordance with SEC rules.

[2] Pre-tax PV-10 value under SEC pricing is consistent with the Standardized Measure calculation, but excludes the effects of future income taxes. We view pre-tax PV-10 under SEC pricing as a useful measure of the value of our proved reserves relative to the values of proved reserves held by other companies as it excludes future income tax expenses which may vary based on the characteristics of the owner of the reserves rather than on the nature, location, and quality of the reserves themselves. We also believe that securities analysts and rating agencies use pre-tax PV-10 under SEC pricing in a similar manner.

[3] Pre-tax PV-10 value under forward strip pricing is consistent with the calculation of pre-tax PV-10 value under SEC pricing, but uses forward strip product pricing instead of average historical pricing as required by SEC rules. We view pre-tax PV-10 value under forward strip pricing as a useful measure of the value of our proved reserves both because it excludes future income tax expenses (as discussed above) and because forward strip pricing provides a more current, forward-looking indicator of value. The pricing used is $75.48/bbl oil and $4.69/mcf gas based on strip pricing as of 1/3/2023.